Impact of CCGT Start-up Flexibility and Cycling Costs Towards Renewables Integration

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***Abstract*—The large scale introduction of variable and limitedly predictable renewables requires flexible power system operation, enabled by, i.a., dynamic power plant operation, storage, demand response and enhanced interconnections. The fast start-up capabilities of combined-cycle gas turbines (CCGTs) are crucial in this regard. However, these non-standard operating conditions significantly reduce the lifetime of critical turbine components, as reflected in long-term service agreements (LTSAs). This should also be reflected in short-term scheduling models. In light of this challenge, we apply a unit commitment model that allows multiple start-up loading modes while accounting for the corresponding turbine maintenance costs based on LTSAs. Leveraging this model, we investigated the need for fast start-up capabilities of a set of CCGTs as part of a small scale test system considering various shares of renewables and dynamic reserve requirements. We have found that fast starts are often cost-optimal despite their greater turbine maintenance costs and a cost reduction of around 1 % is obtained when considering more costly fast start-up modes when scheduling. Furthermore, cost-optimal reserve sizing is a function of the planning frequency and is reduced by fast starting capabilities. We conclude that taking advantage of fast start-up capabilities benefits the electricity generation system and yields a significant cost reduction.**

***Index Terms*—Cycling, combined-cycle gas turbine, power generation maintenance, start-up modes, unit commitment.**

I. Introduction

Wind and solar electricity generation is highly variable and only limitedly predictable. Because of their low marginal generation costs, these renewable energy sources (RES) lower the residual load, to be met by thermal power plants. This is called the "merit order" effect [1]. Furthermore, the absence of a correlation between some RES, such as wind, and system load may cause larger variations in the residual demand profile. This requires thermal units to cycle more, i.e., changing the power output of power plants by starting up, shutting down or ramping up or down [2]. Moreover, the large-scale introduction of intermittent RES requires thermal units to operate more flexibly to follow the partly unpredictable residual load variations.

Combined-cycle gas turbines (CCGTs) play a significant role in power plant cycling as primarily this generation type serves as the marginal generation unit in most systems. The start-up loading rate is one of their most crucial parameters to flexibility. Faster start-ups offer flexibility that enables operators to exploit unforeseen opportunities in today's limitedly predictable market conditions [3].

To draw conclusions on the value of operational flexibility based on unit commitment modeling, the technical limitations of generation units should be adequately represented. This is especially true for CCGTs as they possess the technical characteristics that allow flexible operation. Troy *et al.* [4] presented a formulation that allows CCGTs with a steam bypass stack to switch between open- and closed-cycle modes. Morales-España *et al.* [5] proposed a tight and compact configuration-based formulation to represent the possible configurations in which a CCGT can operate. Wogrin *et al.* [6] expanded on the work in [5] by allowing multiple operating modes in each CCGT configuration in an effort to accurately account for fatigue damage in the heat recovery steam generator depending on the operating strategy. To the best of our knowledge, only Wogrin *et al.* [6] have considered multiple start-up capabilities in a unit commitment model. However, the authors of [4]-[6] did not consider renewable power uncertainty, nor include associated reserve requirements.

The cost of thermal power plant cycling is twofold. The cost of fuel and ancillary services is referred to as the short-term cycling cost and can be determined and accounted for via dedicated models. The thermal stress induced by cycling causes component damage over a longer time horizon, which results in maintenance costs [7]. Accurately representing these long-term maintenance costs in short-term operational decisions is an important challenge in unit commitment modeling. Troy *et al.* [8] implemented a dynamic, incrementing start cost that depends on the preceding scheduling decisions. Rodilla *et al.* [9] extended the work in [8] by making use of long-term service agreements (LTSAs) in the particular case of gas and steam turbines. An LTSA is a contract between the power plant manufacturer and the owner that guarantees the proper gas and steam turbine maintenance over an extended period on a "fixed-price" basis. The maintenance frequency stipulated in an LTSA depends on the operating regime of the power plant, which can be used to calculate a so-called maintenance cost term.

Non-standard operations such as fast starting induce significantly more thermal stress in critical components, leading to increased fatigue damage and a greater reduction of remaining lifetime. Consequently, fast starts require more frequent maintenance procedures than slow starts. This is reflected in maintenance criteria, for instance in [10], where fast starting is deemed to cause damage equivalent to two standard starts in the hot gas-path of gas turbines. LTSAs also apply such a penalization for CCGTs [9], creating a trade-off between increased flexibility provided by greater start-up rates and more stringent maintenance criteria. However, in [9] it was assumed that CCGTs avoid the non-standard operations such as fast starts, even though these damaging events may occur regularly due to the increasing demand for flexible operation of thermal power plants [3].

In [11], the impact of varying the start-up rate and the corresponding turbine maintenance costs of CCGTs on their cycling regime was examined through a sensitivity analysis. In [12], a standard unit commitment formulation [13] was extended to allow multiple start-up loading modes while accounting for the appropriate turbine maintenance costs based on LTSAs. An exploratory case study in [12] investigated the need for start-up flexibility of CCGTs in the presence of a constant day-ahead overestimation of intermittent renewables and limited planning horizons by allowing a faster, but more costly, start-up mode. Fast start-ups were found to be optimal on many occasions, leading to a more cost-efficient operating strategy when considering fast start maintenance penalties. In this paper, we leverage the model in [12] and build on our previous work to contribute to the existing literature in the following three ways:

1) An analytical derivation and a methodological illustration of the incentive for fast starting and its dependence on the forecast error and the cost of fast starting is presented.
2) The planning frequency of the employed rolling horizon method is varied and its interaction with cost-optimal dynamic spinning reserve requirements and CCGT start-up decisions is analyzed in the presence of realistic wind and solar power forecasts. These forecasts are generated via a dedicated tool, leveraging historical forecast and measurement data, and reflect the accuracy of today's forecasting tools. When reserve requirements are considered, the model employs a two-step scheduling approach in which the online/offline statuses of the generation units are determined in a commitment period, i.e. the period in which reserve requirements are enforced, some time ahead of their actual dispatch.
3) Based on a realistic case study, specific maintenance costs of CCGTs are shown to be significant compared to their marginal generation costs. Simulation results illustrate the complex interplay between fast-starting capabilities of CCGT units, optimal spinning reserve requirements and the planning frequency.

With respect to the application, this paper focusses on the operating strategies of a set of CCGTs as part of a small scale test system inspired by Spain, whereas [6] focused on the operations of a single CCGT, i.e., a self-commitment model. As such, a realistic case study investigating the impact of a slow and fast start-up mode on the operational regimes of CCGTs and operational cost components in the presence of renewable power forecast uncertainty, limited planning horizons, various planning frequencies and dynamic spinning reserve requirements is performed.

This paper proceeds as follows: Section II presents the developed methodology and the test system for the case study; Section III presents and discusses the simulation results; Section IV concludes.

II. Methodology

First, we present the modeling of start-up loading modes with the corresponding turbine maintenance costs in the unit commitment model. Second, the unit commitment model in [12] is summarized and the scheduling procedure and test system are described.

A. Modeling the Turbine Maintenance Costs

An LTSA prescribes the preemptive maintenance procedures that the manufacturer recommends to ensure the reliability of the equipment. By far the most expensive and essential maintenance procedure stipulated in LTSAs for CCGTs is the hot gas-path inspection, further referred to as the major overhaul, with an associated major overhaul cost (*MOC*) ranging of 20 to 60 million USD [9].

A maintenance interval function (MIF) is part of an LTSA and defines the combination of firing hours and starts that the plant may maximally accumulate between two major overhauls. The shape of the MIF depends on the manufacturer. Some commonly used shapes are discussed in [14]. This paper assumes a linear shape, as shown in Fig. 1. The maximum number of firing hours FH^{max} and starts S^{max} typically ranges from 8000 to 24000 h and 400 to 1200 starts, respectively [9].

As mentioned above, LTSAs penalize fast starts by assigning to them an equivalent number of slow starts, which increases the maintenance frequency. A unit that always starts fast will thus reach the MIF, hence incur the major overhaul cost, much sooner than a unit that avoids these non-standard operations. With a maintenance penalty α, the MIF for that unit will effectively be scaled down by this factor in the direction of starts. The major overhaul cost is assumed to be linearly dependent on the maximum generation capacity of the CCGT.

Since the number of starts and firing hours required to trigger the maintenance procedure and incur the full major overhaul cost is generally not reached within one simulation period (e.g., 4 weeks), only a fraction of the long-term maintenance cost should be allocated in the short-term unit commitment decision. The method to calculate and allocate this fraction, extensively described in [9], and our adaptation to this method that

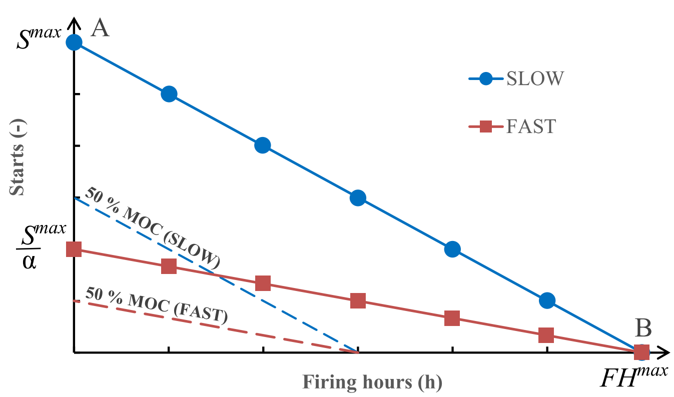

Fig. 1. The maintenance interval function for fast starting units dictates maintenance procedures after fewer starts than for slow starting units.

considers multiple start-up modes, extensively described in [12], is summarized below for the reader's convenience.

The major overhaul cost to be attributed in the simulation period moc_{UC} is dependent on the operating regime in terms of accumulated starts s_{UC} and firing hours fh_{UC}. In Fig. 1, the dashed lines show the fraction (50% in Fig. 1) of the major overhaul cost to be allocated if they are crossed in the case of two different start modes (slow and fast). S_A is the maximum number of starts in the slow start mode S_{slow}^{max} and FH_B represents the maximum number of firing hours FH^{max}. The appropriate maintenance cost can be calculated by summing moc_{uc} in for each start mode l (total number of start modes N_L):

$$moc_{UC} = \left(\sum_{l=1}^{N_l} \frac{s_{uc,l}}{S_l^{\max}} + \frac{fh_{uc}}{FH^{\max}} \right) \cdot MOC \tag{1}$$

B. Unit Commitment Model Description

The total operational cost consists of generation costs (i.e., fuel cost and short-term O&M costs), short-term start costs, and long-term maintenance costs (described in Subsection A). This yields the following objective function:

$$\min_{p_{i,t}, z_{i,t}, v_{i,t}, w_{i,t}} \sum_{i,t} NC_{i,t} z_{i,t} + MC_i p_{i,t} + STC_i \overline{P_i} \, v_{i,t} + moc_{UC,i} \tag{2}$$

with $NC_{i,t}$ the no-load cost of unit i at time t in €/h, MC_i the marginal cost of unit i in €/MWh, $p_{i,t}$ the power above minimum output delivered by unit i at time t in MW, STC_i the short-term start cost of unit i in €/MW/start, $\overline{P_i}$ the maximum output of unit i in MW and binary variables $z_{i,t}$, $v_{i,t}$ and $w_{i,t}$ the on/off, start-up, and shut-down state of unit i at time step t. The number of starts in each mode l and the number of firing hours of each unit must be counted. The time resolution is one hour. Binary variable $d_{i,t,l}$ equals 1 if start-up mode l is selected by unit i at time step t:

$$s_{uc,i,l} = \sum_t d_{i,t,l}, \quad fh_{uc,i} = \sum_t z_{i,t} \qquad \forall i, l \tag{3}$$

Equation (4) ensures that exactly one start-up mode is selected:

$$\sum_l d_{i,t,l} = v_{i,t} \qquad \forall i, t \tag{4}$$

The upper generation limit for power plants is constrained by the upward spinning reserve $r_{i,t}^{+}$, by the start-up rate $SU_{i,l}$ after a start-up in mode l and by the shut-down rate SD_i before a shut-down:

$$\begin{aligned} p_{i,t} + r_{i,t}^{+} \le & \left(\overline{P_i} - \underline{P_i}\right) z_{i,t} - \sum_l \left(\overline{P_i} - SU_{i,l}\right) d_{i,t,l} \\ & - \left(\overline{P_i} - SD_i\right) w_{i,t+1} \qquad \forall i \in MUT_i \ge 2, \forall t \end{aligned} \tag{5}$$

$$\begin{aligned} p_{i,t} + r_{i,t}^{+} &\le \left(\overline{P_i} - \underline{P_i}\right) z_{i,t} - \sum_l \left(\overline{P_i} - SU_{i,l}\right) d_{i,t,l} \\ p_{i,t} + r_{i,t}^{+} &\le \left(\overline{P_i} - \underline{P_i}\right) z_{i,t} \\ & \qquad \forall i \in MUT_i = 1, \forall t \end{aligned} \tag{6}$$

The upward ramping limit (7) is also dependent on the start-up mode and upward spinning reserve:

$$p_{i,t} + r_{i,t}^{+} - p_{i,t-1} \le \sum_l SU_{i,l} d_{i,t,l} \qquad \forall i, t \tag{7}$$

Finally, the market clearing constraint ensures the balance between supply and demand:

$$\sum_i z_{i,t} \underline{P_i} + p_{i,t} + RES_t + lc_t = D_t + rc_t \qquad \forall t \tag{8}$$

With RES_t and rc_t the infeed and curtailment of renewable power, respectively, and lc_t the load curtailment. The lower generation limits, downward ramping limits, minimum up and down time constraints, and binary logic constraints, of which a complete description can be found in [13], further constrain the solution.

The boiler temperature dependence of the fuel-related start-up costs is accounted for as in [15]. Hot, warm and cold starts are distinguished and it is assumed that a warm start occurs when the unit has been offline for at least 8 hours but no more than 50 hours [16]. Evidently, a start-up after less than 8 or more than 50 hours offline time will be hot or cold.

C. Limited Planning Horizon and Renewables Uncertainty

For each time step, it is assumed that the total demand and renewable power can be predicted only a limited number of hours in the future. A scheduling optimization is executed for this limited planning horizon. Fig. 2 illustrates this rolling horizon process. The planning horizon consists of a commitment period A, a dispatch period B and an overlap period C to ensure feasibility and continuity between optimizations. Only the solution for the dispatch period is retained. This solution provides the initial state for the next optimization, for which an updated forecast is made. If period A is only 1 hour, the commitment statuses can thus be changed up to the moment of dispatch (provided the minimum up and down times are respected) which we will refer to as "real time scheduling".

In "dispatch mode scheduling" the online/offline status of the generation units is determined in commitment period B some time ahead of the actual dispatch in A while subject to reserve requirements and forecast errors. In the dispatch period of the subsequent optimization, these commitment statuses are then fixed and only the power output and the selected start-up modes of the units can still be changed. During dispatch, reserve requirements and forecast errors are zero.

To represent the limited predictability of intermittent RES, wind and solar generation scenarios that mimic real forecasts are generated by a forecast scenario generation tool. This data-driven tool, based on the method developed in [17], allows us to generate a realistic wind and solar power forecast for look-ahead times up to 48 hours. The scenario generation method samples from probability density functions of forecast errors, derived from a statistical analysis of wind and solar power forecasts and measurements in the Belgian power system, and

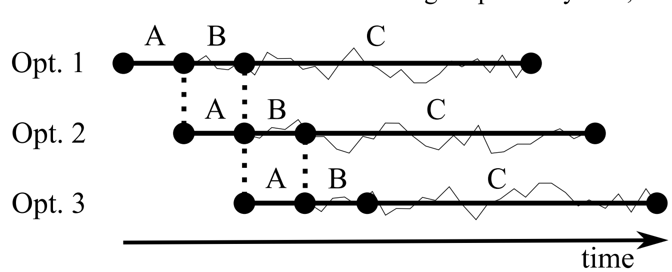

Fig. 2. The planning horizon consists of a commitment period A, a dispatch period B and an overlap period C.

TABLE I
THERMAL GENERATION PORTFOLIO (SPP: STEAM POWER PLANT)

Type	# units	Capacity [GW]	η [a] [%]	STC [b] [€/MW/start]	SU [c] [%$\overline{P}$/h]
Nuclear	1	1	33	6.5-12-23	100
SPP-coal	11	3	40	40.5-61-74	43
SPP-gas	4	1	36	27-45.5-58	50
CCGT	14	5.4	48-58	26-37-74	35-100

[a] The lowest and highest efficiencies are allocated to units commissioned or retrofitted before and after 2000, respectively.
[b] Short-term start-up costs for hot, warm and cold starts are given, respectively.
[c] Start-up rates for possible start modes are given.

TABLE II
PROPERTIES OF CCGT START MODES

Start mode	SU [%$\overline{P}$/h]	S^{max}	FH^{max} [h]
Slow	35	1200	24000
Fast	100	800	24000

the dependency of these distributions on the lead time of the forecast. Forecasts are generated as disturbances of the measured wind and solar power and thus reflect the current accuracy of wind and solar forecasting tools.

D. Test System

The unit commitment model is applied to a small scale test system inspired by Spain. Power plant generation is scheduled for a four-week period except when stated otherwise (for more exact results a two-month period is simulated in some cases). Table I provides an overview of the conventional power plant portfolio. The nuclear power plant is assumed to deliver at least 95% of its maximum output when active. The ramping and shut-down rates of all units are assumed to be unrestricted, as the focus is on start-up rates. The fuel prices are 5.1 €/MWh$_e$ for uranium, 8.4 €/MWh$_{th}$ for coal and 27 €/MWh$_{th}$ for gas [18]. Short-term hot start costs and average ratios of short-term warm and cold start costs to short-term hot start costs for the different generation types were taken from [19], as well as minimum up and down times and part-load efficiencies.

The CCGT units have two possible start-up loading modes, namely slow and fast. In this paper, we assume that the maximum number of starts and firing hours equal 1200 starts and 24000 firing hours respectively, that slow starts are the norm and that one fast start is equivalent to 1.5 slow starts. As a result, the maximum number of starts for a unit that always undergoes fast starts equals only 800 starts. Table II outlines the differences regarding the start-up rates and MIFs of the slow and fast modes. A major overhaul cost of € 40 million for a 400 MW unit or 100,000 €/MW is assumed.

The Belgian demand and renewable generation time series for 2013 were taken from ENTSO-E [20]. In that year, the wind and solar power penetration level was 6.42 % (solar: 2.85 % and wind: 3.57 %), and in the considered four-week period, it was 8.18 % (solar: 5.07 % and wind: 3.11 %). Total Belgian demand equaled 85.6 TWh in 2013 and 6.2 TWh in the considered four-week period. Simulations were run for varying wind and solar energy penetration rates by rescaling the time series (keeping the original ratio between them), within a range of 10–50 % relative to total demand in the simulation period. We did not consider any additional geographical smoothing that may occur at higher RES penetration rates. The RES curtailment cost was set at 0 €/MWh. The optimality tolerance was set at 0.1 %, except when explicitly stated otherwise.

III. RESULTS AND DISCUSSION

In Section III-A, the incentives for fast starting are examined analytically. Then, we demonstrate the benefits of the developed methodology through a cost comparison. In Section III-B, the optimal planning horizon with real time scheduling is determined and the effects of limited planning horizons on scheduling and cost results are evaluated. In Section III-C, the interactions between cost-optimal reserve requirements, fast starts and the planning frequency are investigated.

A. Fast starting analysis and cost benefits

To demonstrate the impact of forecast errors on start-up decisions, an isolated, methodological CCGT scheduling illustration is presented in Fig. 3. Simulation results are shown without (Fig. 3(a)) and with (Fig. 3(b)) a forecast error at time step 3. We observe the differences in a situation at which a high ramping gradient must be satisfied by thermal generation units due to a sudden drop in renewable power. The output of identical 100 MW CCGTs that are started are shown during five time steps. In Fig. 3(a), the future residual load is fully known, and thus the model prepares for the high ramping gradient by slow starting both CCGTs one time-step in advance such that they can satisfy the ramping requirement by ramping up in the next time step. Note that in this illustration, renewable power is curtailed in order to start in advance. In Fig. 3(b), the model underestimates the ramping requirement in the next time-steps due to a positive forecast error. Therefore, it only schedules one CCGT to start up in the slow mode in time step 2. When the true residual load is revealed in the next time step, the model is forced to make a decision between starting two or more CCGTs in the slow mode and starting one CCGT in the fast mode. As we can see, the optimal decision is the latter, despite the greater turbine maintenance costs for fast starts. However, if the penalty for fast starting is increased (e.g., penalty $\alpha = 3$), the optimal decision is to start two CCGTs in the slow mode, as shown in Fig. 3(c).

This result can be explained as follows. Imagine that a generation portfolio of identical CCGTs must satisfy a challenging ramping requirement in the next time step. One or more units must be started if the online units cannot satisfy this increase with demand. The start-up ramping rate of two CCGTs

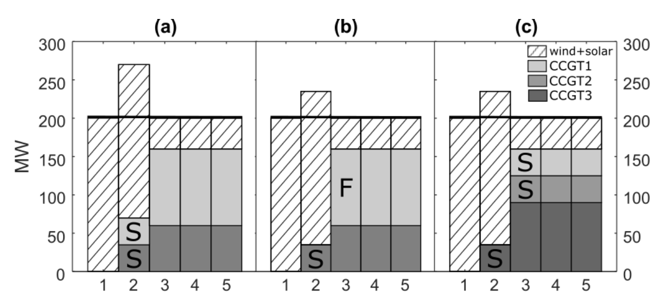

Fig. 3. CCGT scheduling decisions (S: slow start, F: fast start) (a) without forecast error, (b) with forecast error (and $\alpha = 1.5$), (c) with forecast error and increased fast start maintenance penalty ($\alpha = 3$). Total demand: thick line.

in the slow mode might suffice, but instead, the model may opt to start only one CCGT in the fast mode, if the following inequality holds:

$$STC_i^{hot} + LTC_i^{fast} < 2 \cdot (STC_i^{hot} + LTC_i^{slow}) \quad (9)$$

with LTC_i the long-term start-up maintenance costs of unit i. If we define α to be the fast starting penalty, (9) can be reduced to:

$$(\alpha - 2) \cdot LTC_i^{slow} < STC_i^{hot} \quad (10)$$

If the maintenance penalty α is smaller than 2, (10) always holds, and thus fast starting is optimal regardless of the short-term costs. With the short-term costs of the test system, the turning point of α below which (10) holds and a fast start is optimal occurs at $\alpha = 2.31$ (assuming hot start-ups). The turbine maintenance costs caused by a fast start may maximally be 2.31 times greater than by a slow start before two slow starts are preferred (c). Note that this analysis concerns the optimal start-up decisions while only considering the hot short-term start-up costs. Other cost considerations such as the non-linear fuel cost function, minimum up and down times, and the part-load efficiency drop slightly shift this turning point up to 2.55 in this illustration (as determined by iteration).

Cost results for the test system are compared in Table III to demonstrate the benefits of applying the developed methodology to allow multiple start-up modes and account for their corresponding turbine maintenance costs. Table III compares the results of a scenario with 28 % wind and solar power penetration for a two-month period and a 24 hours planning horizon in real time scheduling in the following cases:

- Case W-PF, taking long-term maintenance costs into account when scheduling with perfect foresight, i.e. no forecast errors
- Case W, taking long-term maintenance costs into account when scheduling with imperfect foresight
- Case WO, not taking these into account when scheduling with imperfect foresight but adding them ex-post
- Case S, where only slow starts are allowed, with imperfect foresight

The cost differences between case W-PF and case W thus represent the balancing cost of wind and solar power, which amounts to 4.90 M€ (2.21 %). Note that in this case, all CCGT starts were in the slow mode as you can plan for ramping events (as in the methodological illustration in Fig. 3 (a)). Case WO shows the actual costs if the turbine maintenance cost penalties for fast start-ups would have been disregarded. Accounting for fast start maintenance penalties results in a different optimal operating strategy, leading to lower total costs. Compared to case W, the total operating costs for the two-month period are 2.36 M€ (1.07 %) higher in case WO. Disregarding the turbine maintenance penalties leads to higher maintenance costs during planning (as calculated ex-post). The generation costs are slightly increased in case W, indicating a trade-off between the maintenance and generation costs. The CCGTs compromise a small amount on operating fuel-costs to save a greater amount on turbine maintenance costs. The total cycling costs, comprising short-term start costs and turbine maintenance costs, declines by 10.13 %. Finally, the total operational cost is again greater in case S. We observe lower turbine maintenance costs and slightly greater generation costs. The short-term start costs are greater, as more slow starts are required to provide the same system flexibility than when fast starting is an option. This indicates that taking advantage of both start-up modes results in more optimal scheduling decisions.

TABLE III
COST RESULTS FOR THE TEST SYSTEM IN CASES W-PF, W, WO AND S. OPTIMALITY TOLERANCE: 0.01 %.

	Case W-PF M€; [%]	Case W M€; [%]	Case WO M€; [%]	Case S M€; [%]
Total operational cost	217.06; [100]	221.96; [100]	224.00; [100]	222.10; [100]
Generation costs	194.56; [89.64]	195.29; [87.98]	194.37; [86.78]	195.70; [88.11]
Short-term start costs	8.85; [4.08]	10.18; [4.59]	10.03; [4.48]	10.32; [4.65]
Maintenance costs	13.51; [6.23]	16.35; [7.37]	19.49; [8.70]	15.95; [7.18]

B. Impact of renewables and planning horizon

The impact of limited planning horizons on the scheduling results of a four-week period was investigated in real time scheduling. Fig. 4 shows the total operational cost and its components, as well as the total number of CCGT starts and the share of starts in the fast start mode.

The generation units are forced to cycle more often with growing shares of renewables. As a result, total start-up costs increase. The CCGT start costs do not increase past 30 % renewables because fewer CCGTs are required to meet the residual load peaks, as shown by the number of CCGT starts. The turbine maintenance costs drop with increased wind and solar power penetration because the number of firing hours is greatly reduced, even though the number of CCGT starts increases up to 30 % renewables. As an increasing share of demand is supplied by renewables, the generation costs are reduced, hence the total operational costs reduce.

To find the optimal planning horizon, optimizations were run for various scheduling periods B+C (Fig. 2). We observed that the total operational costs decline until a planning horizon of around 24 hours. To investigate the impact of the planning horizon on the operational cost components and scheduling decisions, Fig. 4 presents the results for the optimal horizon of 24 hours, a very short 4 hours horizon and an intermediate 12 hours horizon.

It is clear from Fig. 4 that in the presence of forecast errors and a limited planning horizon, fast starts are often preferred over slow starts, meaning they are optimal despite their greater turbine maintenance costs. As the share of intermittent renewables grows, this happens more frequently, ranging from 4 to 20 % of total CCGT starts.

The planning horizon length has a significant impact on the number of CCGT starts and total starts and their short-term costs, but the impact on the number of fast starts is negligible. Below 30 % renewables, the total number of CCGT starts is greatly reduced by longer planning horizons, whereas we observe the opposite effect above 30 % renewables, which is reflected in the CCGT start costs and turbine maintenance costs.

The reason for this is that with a very short planning horizon, the model can only optimize costs in the short-term, meaning it will dispatch the generation units according to their position in the merit order instead of keeping some units with higher marginal cost online in short residual demand valleys to avoid future short-term and long-term start-up costs. At low renewables penetration rates, the residual load often exceeds the nuclear and steam power plant capacity, followed by relatively short periods of low demand. A very short planning horizon does not allow the model to see that the residual load will soon rise again, thus, some CCGTs are shut down and restarted only a few hours later, incurring considerable short-term and long-term start costs. However, a longer planning horizon will keep some CCGTs online at part load to avoid these start-up costs, thus reducing the number of starts. In contrast, at high renewables penetration rates, the residual load is greatly reduced during daytime by solar power, causing all CCGTs to be shut down regardless of the planning horizon. Again, a long planning horizon allows the model to see that after sunset, some CCGTs will be required to restart. Therefore, to keep more CCGTs warm, some will then be preferred over the gas-fired steam power plants. However, the above mentioned effects cause the total number of starts per 100 firing hours to be greater for short planning horizons at low renewables and similar at high renewables.

The total start costs increase greatly with a shorter planning horizon. The generation cost however, which is the greatest cost component, is around 1 % greater for the 4 hour planning horizon at any share of renewables. Adding these effects, we find that the total operational cost is around 0.8 – 2 % greater, depending on the share of renewables, for the 4 hours planning horizon with respect to the optimal horizon of (at least) 24 hours.

Fig. 4 also presents the turbine maintenance cost ranges of

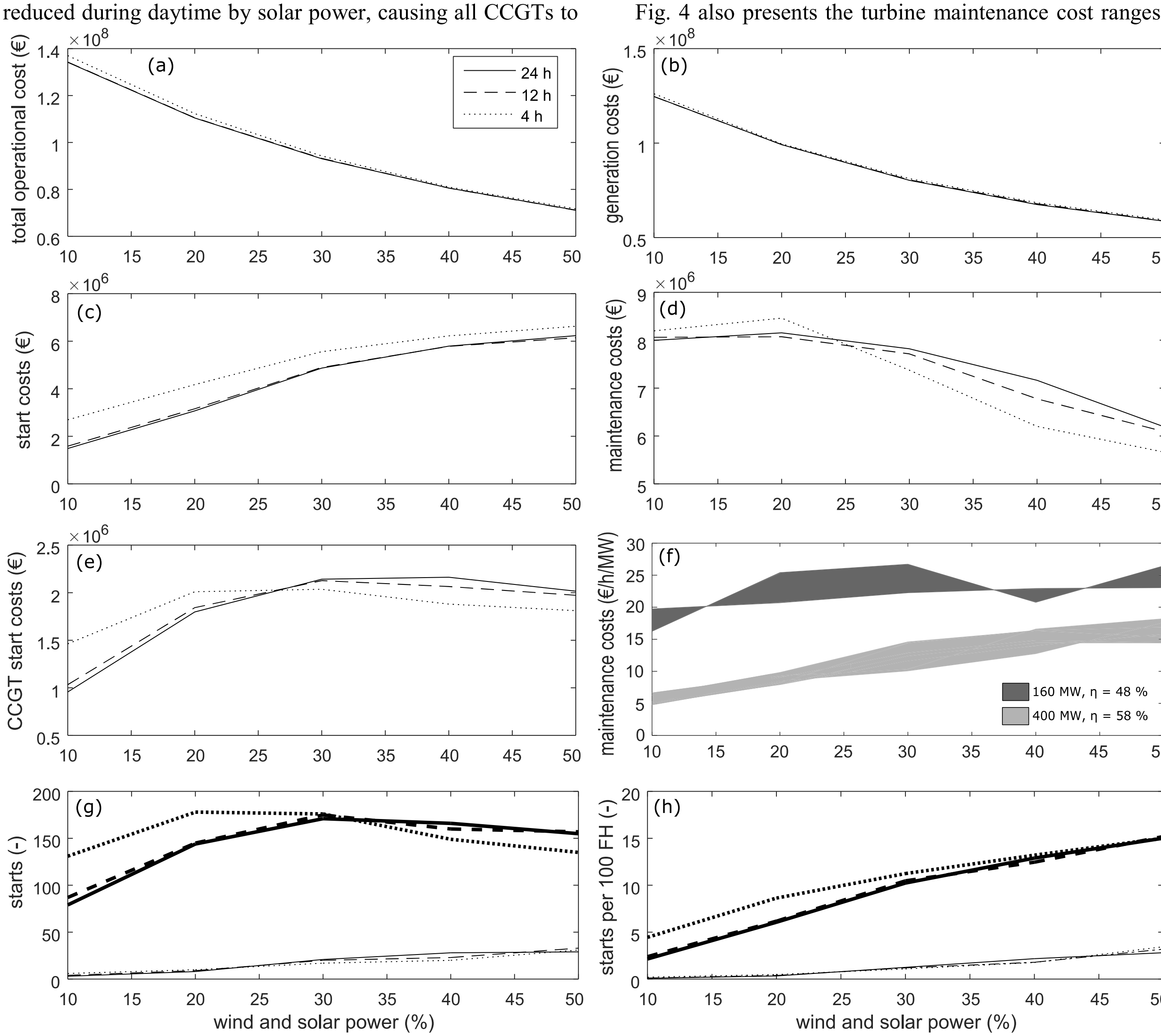

Fig. 4. The total operational cost (a), the generation costs (b), the total short-term start costs (c), the CCGT short-term start costs, the turbine maintenance costs (d) and the specific turbine maintenance cost ranges for active CCGT units (24 h planning horizon) (f) obtained with real-time scheduling. The total (thick lines) and fast (thin lines) number of CCGT starts in absolute terms (g) and per 100 CCGT firing hours (h). Graphs are shown for three different planning horizons as a function of the overall solar and wind power penetration. Solar and wind power are considered in a fixed ratio of 1.63:1.

the active CCGT units as a cost metric in € per MW unit capacity $\overline{P_i}$ per firing hour (€/MW/h), i.e., the specific turbine maintenance cost. This maintenance cost should be compared to the marginal generation cost of CCGTs of around 50 €/MWh$_e$. There is a cost increase with growing shares of renewables as a result of a decreasing number of firing hours while the number of starts increases and then stagnates. Furthermore, we clearly observe two separate ranges. The majority of the CCGTs are in the low range, for which the turbine maintenance costs increase from 6 to 16 €/MW/h. These units are relatively new (commissioned or retrofitted after 2000) and have a greater efficiency than the older units (Table I). These older units make up the top range, for which the turbine maintenance costs increase from around 17 to 25 €/MW/h. Aside from their lower efficiency, the older units in this simulation also have a lower capacity $\overline{P_i}$. Further analysis of these differences show that both smaller unit size and lower efficiency significantly impact the specific turbine maintenance cost. We observe that these units have the lowest firing hours to starts ratios, because they are being used as peaking units. Thus, the turbine maintenance costs resulting from a similar number of starts must be spread out over fewer firing hours. The impact of the efficiency can easily be explained by noting that more efficient units with the same operational flexibility will be lower in the merit order than those with a lower efficiency.

C. *Impact of Spinning Reserves and planning frequency*

As unexpected deviations from the forecasted renewable generation regularly occur, sufficient operational flexibility must be available in real time. Reserves can be scheduled to manage the limited wind and solar power predictability. A trade-off exists between the cost of scheduling reserves and the socio-economic cost of load shedding. Here, the impact of spinning reserve requirements on scheduling results is investigated with dispatch mode scheduling, while subject to wind and solar power uncertainty and limited planning horizons. We have assumed a 30% wind and solar power penetration and a load curtailment cost of 3000 €/MWh. Fig. 5 shows the total operational cost and the number of fast CCGT starts in function of the spinning reserve requirements as a percentage of the forecasted wind and solar power with dispatch periods of 24, 12 and 4 hours. The results for real time scheduling are also shown. Period B+C (Fig. 2) is set to 24 hours in all cases.

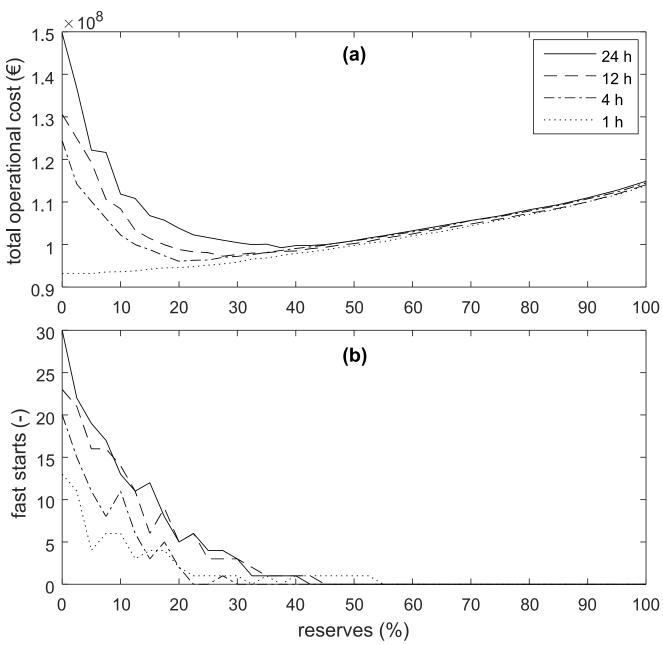

Fig. 5. Total operational cost (a) and number of fast CCGT starts (b) in function of spinning reserve requirement with dispatch periods of 24, 12 and 4 hours and a total horizon of 48, 36 and 28 hours, respectively. The results for real time scheduling (horizon of 1 h + 24 h) are also shown.

TABLE IV
OPTIMAL SPINNING RESERVES SIZING IN CASES W AND S

Dispatch period (h)	Case W		Case S	
	(%)	(M€)	(%);	(M€)
24	37.5	99.3	40	99.9
12	27.5	97.2	37.5	98.6
4	20	96.1	22.5	96.4

With real time scheduling, the thermal units can maximally react to realizations of the limitedly predictable residual load before dispatch by adjusting their commitment statuses accordingly. Consequently, there is no load shedding even at 0 % spinning reserves and increasing reserves merely increases the operational costs due to scheduling inefficiencies following from overly conservative reserves scheduling.

With dispatch mode scheduling however, a trade-off between the cost of scheduling reserves and the cost of load shedding is apparent. The optimal reserve sizing is a function of the planning frequency (all else being equal). It reduces from 37.5 % (24 h) to 20 % (4 h) while total operational costs decrease by 3.2 M€. A reduction of the dispatch period allows the thermal units to better anticipate the residual load, thus lowering operational costs.

We have found that at low levels of reserves, CCGT units regularly schedule a slow start in the commitment period, but then adjust this to a fast start in the dispatch period to cope with forecast errors. The number of fast starts decreases with increasing reserves until fast starting no longer occurs. The part-load operation of the units providing spinning reserves will cancel out the need for start-up flexibility when an overestimation of renewable power becomes apparent because these units will be able to cover the forecast error by ramping up.

Note that the point where fast starts are no longer scheduled is reached beyond the optimal amount of spinning reserves. Therefore it is interesting to investigate the interaction between the optimal reserve sizing and the fast start capability of CCGTs. Indeed, it is evident from Table IV that both the optimal amount of reserves and the corresponding operational cost are increased when the fast starting mode is disabled (case S). The impact is most significant with a dispatch period of 12 hours. Furthermore, we have observed that the operational cost increase in case (S) is yet more severe at zero reserves, with a cost difference of 5 % (4 h) to 7 % (24 h) compared to case (W). In summary, the fast starting capability can considerably reduce the cost-optimal reserve requirements and the operational costs at sub-optimal reserve requirements.

IV. Conclusion

The large-scale introduction of intermittent RES requires thermal units to operate more flexibly to follow the partly unpredictable residual load variations. Fast start-up capabilities of CCGT units are one of the most crucial ways to cope with this uncertainty. Here, a unit commitment model was set up that allows operators to take full advantage of the flexibility of their thermal power plants by allowing multiple start-up loading modes. Furthermore, the model accurately accounts for the corresponding turbine maintenance costs for CCGT units based on their LTSAs. This enables us to obtain the optimal dispatch schedule of a power plant portfolio when multiple start modes are allowed and their implications on maintenance costs are considered. Furthermore, a limited planning horizon was simulated by means of a rolling horizon approach in which the planning frequency was varied. The possibility to impose a period in which the commitment statuses are fixed prior to the actual dispatch of the unit was also included. The limited wind and solar power predictability was modeled by generating realistic forecast errors and updating the forecasts at every step of the rolling horizon process. Finally, dynamic spinning reserve requirements were imposed.

First, an analytical derivation and a methodological illustration of the incentive for fast starting showed that, depending on the maintenance penalty, fast starts can be preferred over slow starts to cope with forecast errors. This was confirmed by analyzing the power plant schedules, indicating fast starts are often optimal despite their greater turbine maintenance costs. Second, a cost comparison has shown that an optimal operating strategy leading to a total cost reduction of around 1 % and a cycling cost reduction of around 10 % is obtained when accounting for fast start maintenance penalties when scheduling. Third, we have investigated the impact of a slow and a fast, but more costly, start-up mode on the scheduling decisions of CCGTs and operational cost components in the presence of intermittent renewable power and limited planning horizons. The turbine maintenance costs comprised around 8% of the total operational costs. Also, the specific turbine maintenance costs of CCGTs were found to be significant in comparison to their marginal generation costs. Furthermore, the modeling results showed that both smaller unit size and lower efficiency considerably increase their specific turbine maintenance cost. Regarding limited planning horizons, the total operational cost was noticeably greater (0.8 – 2 %) for the 4 hours planning horizon than for the optimal 24 hours horizon. Finally, the impact of a dynamic spinning reserve requirement on the scheduling results was investigated. We observed that the optimal reserve sizing is a function of the planning frequency and that the fast starting capability affects the cost-optimal reserve requirement and the operational costs.

The results in this work demonstrate that increased CCGT start-up flexibility in the form of multiple start-up loading capabilities benefits the electricity generation system despite higher maintenance costs and that representing these capabilities in a unit commitment model can yield a significant cost reduction. Note that the start-up procedure prior to start-up loading (e.g. purging and synchronization) was not considered in this work. Future work will address the complete start-up lead time between decision making and actual start-up ramping of generation units and consider other common types of maintenance interval functions, more start-up modes and the sensitivity to the major overhaul cost. This may help power plant operators to gain more insight on the characteristics of LTSA contracts to better negotiate the terms of their LTSAs by allowing their CCGTs to cycle at lower costs.

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